Feasibility Study and Simulation of Adding Hydrogen Fuel to a Combined Cycle Natural Gas Combustion Turbine at an Electric Generation Plant

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Executive Summary

Hydrogen has become an important topic of discussion within the context of green energy. This is due to hydrogen's infrastructure's similarities to natural gasses, and its capability for direct substitution in chemical and combustion processes. The use of hydrogen has significant potential to greatly reduce carbon emissions, the term "Hydrogen Economy" has been coined to reflect how much potential it has to change how energy is produced. The Northern Indiana Public Service Company (NIPSCO) currently runs a combined cycle natural gas turbine (CCGT) in their Sugar Creek facility in Terre Haute, Indiana. This report describes current research on the conversion of CCGT's to hydrogen to reduce carbon dependency and the use of computational fluid dynamics (CFD) to create a baseline model that runs on natural gas to use as validation in future studies. In addition, a basic comparison of hydrogen to natural gas has been developed for preliminary study.

Today, green energy is spreading across all major industries. The energy sector has seen massive changes in the diversification of energy production using alternative fuels. Large companies such as NIPSCO have begun shifting their energy production methods away from natural gas and coal to cleaner fuels such as solar, wind, water, and hydrogen. Using hydrogen instead of natural gas will reduce the carbon emissions of power plants.

The research described in this report indicates current models of CCGT's –such as the one NIPSCO owns –have been converted to run partially on hydrogen up to a capacity of 65%. The model described in this report will be used to determine the feasibility of converting their combined cycle gas turbines to a fully hydrogenated or blended mixture (hydrogen mixed with natural gas). Through analyzing the chemical and fluid physics of the combustion system in a CCGT, it is hoped that an understanding of some of the pitfalls as well as benefits of the conversion will be identified. These include additional wear on equipment, increased heat of combustion, and unaccounted pollutants and emissions.

A generic combined cycle gas turbine can-combustor model was developed, and computational fluid dynamic simulations performed to analyze as close as possible to the GE7F series turbine that the Northern Indiana Public Services company operates. This model simulated various percentages of Hydrogen to analyze the impact Hydrogen combustion has on the performance, materials, and emissions of the system.

In this body of research many assumptions were made about the geometry and operating conditions due to the restriction on information obtainable due to export laws, the International Traffic in Arms Regulations (ITAR), and what information NIPSCO was able to provide. With this limitation on the scope of the project, meaningful results were still obtained that demonstrate the chemical interactions that Hydrogen has on natural gas combustion. In addition, insights were developed on its impact on emissions, performance, materials, and flue gas composition.

It is hoped that the insights within this senior design project are useful and demonstrate the feasibility of incorporating Hydrogen as an alternative fuel source for industrial combustion processes. In addition, its furthered hoped this research inspires further work in this important field of study and with combustion simulation. Much was learned over the past year and enjoyed developing this model and analyzing the results to this engineering problem.

Abstract

In the electric power industry, organizations are investigating transitioning combined cycle turbine power plants (CCGT) from natural gas to hydrogen combustion to decrease dependance on fossil fuels. In the interim, hydrogen can serve as a compliment to natural gas and syngas as an additional fuel source to protect corporate profitability from price volatility. Transitioning to hydrogen fuel or hydrogen blended fuels adds complications as there are many variables to consider such as combustion temperature, change in heat transfer modes, mass flow rate, chemical composition of flue gas, rate of combustion, nitrogen oxide (NOx) production, etcetera. This research and design project reviews current work in the transition of combined cycle turbine engines to hydrogen fuel and the development of a parametric computational fluid dynamics (CFD) study of natural gas and hydrogen combustion. A generic can combustor design was used to develop an academic model of GE Power 7F04 gas turbine combustor. Using the total capacity (MW) of the engine, calculations were performed to determine the amount of fuel required to produce an equitable amount of thermal energy. From these calculations, a baseline computational fluid dynamics model was developed, and the geometry was scaled accordingly. This model was used alongside additional calculations to determine mass fractions and mass flow rates from the heat of combustion of blended hydrogen and natural gas. A parametric computational fluid dynamic simulation study was performed to determine the impact of hydrogen has on the performance, materials, and flue gas composition of the combined cycle gas turbine engine combustor.

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Introduction

In 2021, the United States received 79% of its energy from the combustion of petroleum, coal, and natural gas. In contrast, renewable energy sources and nuclear power only contributed 12 percent and 9 percent respectively [1]. As green energy technology further develops to become a leader in energy production, combustion will still be a necessary component in our energy production infrastructure. This is due to energy consumption rates exceeding that of what can be produced by current green technologies and limited green infrastructure. In addition to technological limitations, other sources of clean energy, such as nuclear power, will continue to be politically unfavorable and therefore heavily regulated into the foreseeable future [2].

To combat carbon emissions due to the combustion of fossil fuels, a few states have developed a carbon credit system in which companies are permitted to emit a set amount of tons of pollution. If a company needs to emit more to maintain operations, they can offset those emissions with green technologies or purchase unused carbon credits from other companies. Local and Federal governments have also subsidized green technologies by giving tax or other incentives for their adoption. Many industries have opposed this legislation, and many are concerned with the legislation on the horizon: a carbon tax. A carbon tax's goal is to make green energy more cost-competitive with traditional sources of cheap energy by effectively internalizing the costs of carbon emissions-related climate change [3].

Indiana remains behind the national average in the adoption of clean energy production. In the state, 89% of all energy consumed came from fossil fuels. Indiana is also the third largest total consumer in the United States of coal for electricity and the Hoosier steel industry accounted for 47% of the total end-use of energy produced in the state [4]. In 2021, the Northern Indiana Public Service Company (NIPSCO) announced they would be increasing their green energy portfolio and the retirement of two coal-fired plants. The plants closing include the Schahfer Generating Station (May 2023) and the Michigan City Generating Station (End of 2028) [5]. To prepare and position itself for future federal carbon emission regulation, NIPSCO is investigating transitioning a combined cycle natural gas combustion turbine located at the Sugar Creek Generating Station in Terre Haute to hydrogen or a combination of hydrogen and natural gas combustion [6]. Hydrogen combustion eliminates carbon emissions as the only exhaust from the combustion reaction with oxygen is water vapor. A combined cycle gas turbine is a land-based turbine, like that of a jet engine on an aircraft, where the exhaust of the first stage is then plumbed into a secondary stage to drive a secondary turbine. This report will focus on the first stage combustion chamber, analyzing a combination of natural gas and hydrogen combustion within.

Background

The following sections are an in-depth literature review regarding background information of combined cycle turbine power generation, design, and physics. In addition, computational fluid dynamics principles are explained in detail regarding the application of computational fluid dynamics in reacting flows.

Combined Cycle Turbine Power Generation

A combined cycle gas turbine (CCGT) is a three-stage power generating design that takes advantage of the power produced dominantly by an axial land-based turbine and converts rotary motion and thermal energy into electricity. This is achieved in the following three stages (Figure 1):

1. A gas turbine mixes high pressured air with fuel and burns the fuel. The exhaust turns the turbine within producing electricity.
2. The exhaust is plumbed into a heat recovery steam generator (HRSG) which captures the heat from the exhaust and converts it into high pressure steam.
3. The steam is then fed to a secondary steam turbine where the waste heat held in the steam is also transformed into electricity.

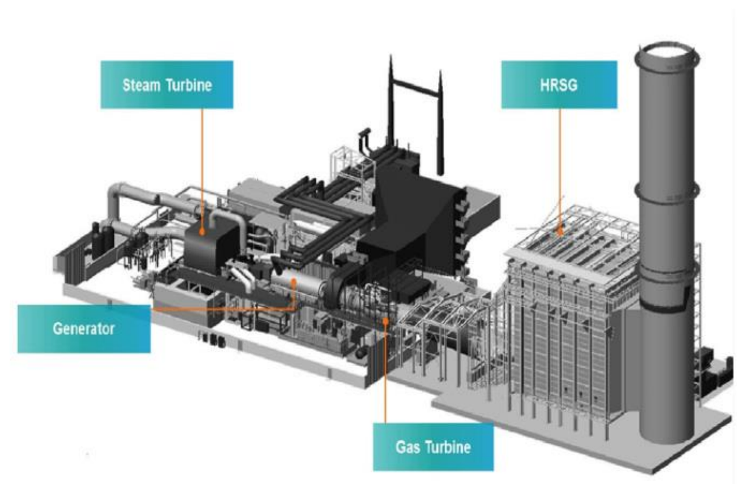


Figure 1. Typical Combined Cycle Gas Turbine Power Plant [14].

CCGT power plants have become increasingly popular due to their cleaner combustion in comparison to coal fired plants. In addition, combined cycle power plants are very efficient and can produce upwards of 50% more electricity than a simple single cycle generation plant [15].

The Combined Cycle Gas Turbine (CCGT) power plant used by NIPSCO at Sugar Creek Generating Station is a typical 2 x 1 combined-cycle facility with two 7FA gas turbine/generators and one D11 steam turbine/generator supplied by GE Energy. GE states that the latest model of F7 turbines have a 60% combined cycle efficiency and with modifications can have up to an 65% hydrogen capability.

The Brayton cycle is a fundamental thermodynamic process that is central to the design and operation of any turbine engine. The Brayton cycle operates through three primary stages. The three stages are: compression of the incoming air, combustion, and then expansion. The first step is theoretically isentropic (constant entropy), the second is isobaric (constant pressure), and the third is also isentropic as it is a reversal of the first stage as shown in the temperature and entropy diagram (Figure 2). However, in reality the operation is far from ideal [15].

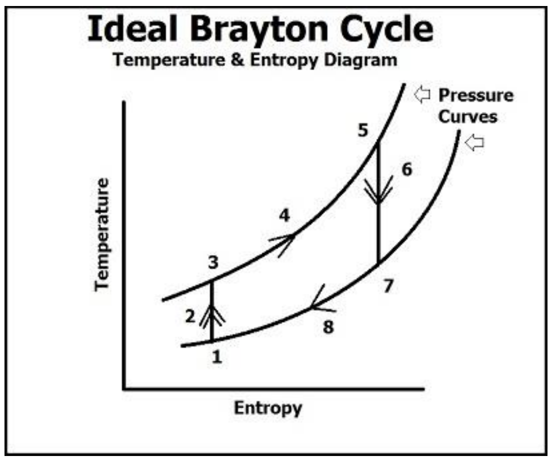


Figure 2. Ideal Brayton Cycle Diagram [15].

Combustor

Gas turbine engines are preferred in several different applications over steam and internal combustion engines (ICE) where efficiency and power density, the power output per unit volume, is critical. The most common applications include commercial air transportation and power generation. Within the axial turbine, such as those found in power generation and aviation, nearly all components are designed to optimize the flow characteristics around the combustor. From the fan and through the numerous complex compressor stages, prior to the combustor, the turbine blades and stators are optimally designed, and precision manufactured to efficiently slow the air velocity of the free stream air, increasing the static pressure. After fuel is mixed with the incoming high-pressure air and combusted within the combustor, the turbine stages are designed to maximize capturing as much of the expelled energy as possible while also converting high pressures and temperatures back to high velocity flow to eject out of the nozzle [7].

With this considered, the combustor, is equally critical to the operation of the turbine. The combustor section of an axial turbine is the location of the greatest pressure drop, thus the greatest power loss in the engine. The combustor is also central to the efficiency and performance. Furthermore, the operation temperature and fuel to air ratio has the greatest impact on pollution in the exhaust. Because of the high pressures and lean combustion, combustors operate at higher temperatures, and thus are prone to producing NOx (Nitrogen Oxides). In land-based turbines, such as those found in electrical power plants, NOx formation is reduced through water injection. Water injection acts as a thermal energy sink, increasing the enthalpy of the injected water, ultimately causing a phase change from liquid water to steam, and reducing the temperature [7].

Combustion chamber design is difficult in an axial turbine as the combustor must maintain constant combustion despite high flowrate which can often extinguish the flame. To combat flame-out conditions, combustors are designed to premix the fuel and air prior to combustion. Since the inception of the jet turbine, there exists three main designs: can, annular, and can-annular. A can combustor was selected for simulation as this most closely matches the design type in the field. Common to all three designs, the combustor contains the same main components. Starting from the inlet, there are swirl vanes to increase the vorticity of the incoming air. The swirl vanes increase the vorticity of the incoming air and is crucial to cooling, fuel and air mixing, and cooling of the flame tube. Nearby the swirl vanes is the fuel nozzle. The purpose of the nozzle is to inject and aerosol the fuel, increasing the surface area of the fuel for ideal combustion. Just aft of the swirl vanes and fuel injection nozzle is the primary combustion zone. This is where most of the combustion happens. Within the primary zone, the main design goal is flame stability. Further back is the secondary holes which increase the air to fuel ratio, which adds additional air to further complete combustion. Finally, there is the dilation zone where the dilation holes are located. These aid in cooling the combusted products prior to the turbine stage. Without dilation holes, the gases entering the turbine could damage the blades and other components (Figure 3). The combustor has historically been designed experimentally with analytical equations scaling features to the expected flow rates and output energy. However, computational fluid dynamics simulations are further increasing the performance and efficiency of legacy designs.

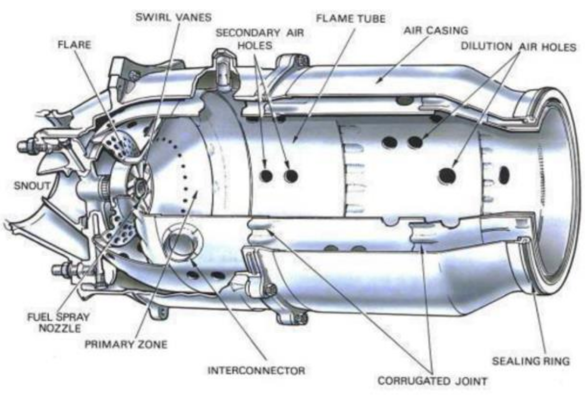


Figure 3. Typical Can Combustor [8].

Combustion

Within a gas turbine engine's combustor is turbulent premixed combustion. This type of combustion occurs when the incoming air is highly turbulent, and the fuel and oxidizer are mixed prior to combustion. The advantage of this type of combustion is excellent NOx control, however, at the cost of turndown ratio (throttling ability), flame stability, and carbon monoxide emissions [8]. Whilst a combined cycle gas turbine is burning natural gas, the global chemical reaction equation is the following:

$$CH_3 + (O_2 + 3.76N_2) \rightarrow CO_2 + H_20 + (3.76N_2) \tag{1}$$

And the blended fuel, hydrogen and natural gas global reaction is

$$CH_3 + \ H_2 \ + \ (O_2 + 3.76N_2) \rightarrow CO_2 + H_20 + (3.76N_2) \tag{2}$$

And pure hydrogen,

$$H_2 \ + \ (O_2 + 3.76N_2) \rightarrow CO_2 + H_20 + (3.76N_2) \tag{3}$$

In land-based combustors in industries that are heavily regulated by the EPA, it is common for the combustor to be injected with atomized water. The water absorbs energy from the reaction and reduces the flame temperature. This is critical in the reduction of NOx emissions [7].

If water is injected, the above equations take the form:

$$CH_3 + \ (O_2 + 3.76N_2) \ + \ H_20 \ \rightarrow CO_2 + H_20 + (3.76N_2) \tag{4}$$

$$CH_3 + \ H_2 \ + \ (O_2 + 3.76N_2) + \ H_20 \ \rightarrow CO_2 + H_20 + (3.76N_2) \tag{5}$$

$$H_2 \ + \ (O_2 + 3.76N_2) + \ H_20 \ \rightarrow CO_2 + H_20 + (3.76N_2) \tag{6}$$

In contrast to laminar flames, turbulent flames depend on the flow characteristics of the reactants and the characteristics of the reaction [17]. Turbulent flames often have a jagged flame front and change constantly with time (Figure 4).

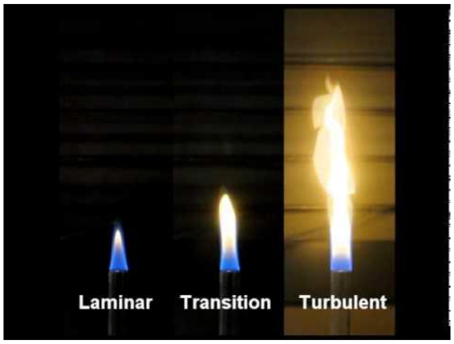


Figure 4. Comparison of Laminar vs. Turbulent flames [9].

In turbulent combustion the flame can be characterized by three flame regimes; wrinkled laminar-flame, distributed-reaction, and flamelets-in-eddies regime. The determination of these regimes is known as the Williams-Klimov criterion and distributed reaction zones are determined by the Damkohler Number, Da. The Damkohler is defined below:

$$Da = \frac{characteristic\ flowtime}{characteristic\ chemical\ time} = \frac{\tau_{flow}}{\tau_{chem}} \tag{7}$$

Depending on the combustion regime, calculations change significantly as the flow and chemical characteristics are different. This is due to the impact the eddies and mixing have on the reaction which will alter the flame and reactant surface areas but also the gas mixture of reactants and products. This change in physics ultimately changes the burning rate of the reactants. For gas turbine combustion, flamelets-in-eddies regime will be assumed as experiments show that this is the most common regime in high energy reacting flows.

To stabilize the flow, many devices are employed in combustor design to reduce flashback, liftoff, and blowoff. These include:

- Low-velocity bypass ports
- Refractory burner tiles
- Bluff-body flameholders
- Swirl or jet-induced recirculating flows
- Increase to flow area

The combustor design described in the combustor design section takes advantage of these design criterion [17].

Computational Fluid Dynamics

Computational fluid dynamics (CFD) is a numerical method of obtaining a solution of fluid flow. The method is a technique that is replacing the fundamental analytical transport equations in which numerical data is input and the solution output is also numerical data [12]. In modern solvers a graphical post-processor is used to aid in the interpretation of the data. Such stand-alone example of such is Paraview.

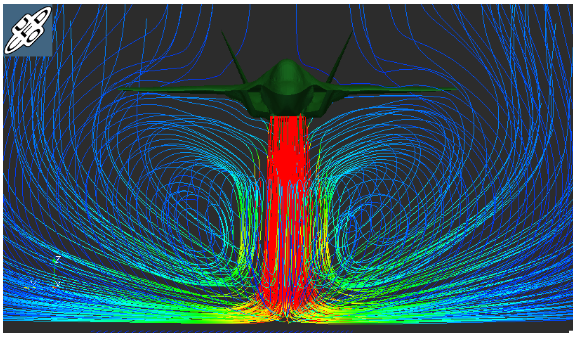


Figure 5. Example of Post-Processor adding Contour Lines [11].

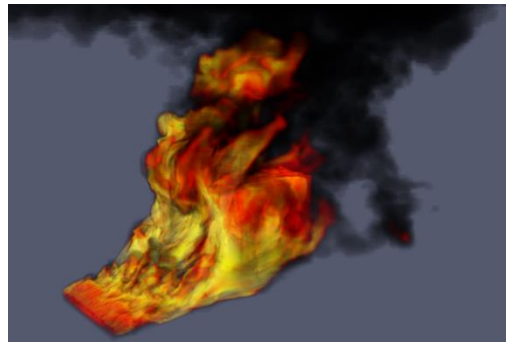


Figure 6. Example of a Contour Plot in Paraview [11].

The application of numerical methods can be traced back to the 1940's, however, was not really employed until the Space Race of the 1950s and 1960s. Up until the late 1990's, CFD computation was primitive due to technological and computational limitations. During this time, supercomputers, multicore, and multiprocessor machines became cost effective and practical. During this time, graphical processing units (GPUs) were also seeing huge improvements. Thereafter, researchers realized their parallel computational power potential. In modern times, we are seeing more codes take advantage of the available processing power of modern machines, opening doors to advanced analysis and new methods. Since computer hardware capability has enabled the handling of larger data sets, CFD as a primary design tool has become a reality. This makes CFD as a tool rather than a research subject relatively new and the potential of CFD solvers has yet to be reached [12].

The Navier-Stokes equations form the foundation of computational fluid dynamics. They are a derivative of Newton's Conservation of Mass, Momentum, and Energy. Although Newtonian physics are well understood and validated, the Navier-Stokes equations have yet to be proven to exist in all domains and to be continuous. However, they are assumed to be true as the underlying principles are [13]. The Navier-Stokes equations for incompressible (sub-sonic) flow are as follows:

$$\nabla \cdot \vec{V} = \frac{du}{dv} + \frac{dv}{dy} + \frac{dw}{dz} = 0 \tag{8}$$

$$\rho \frac{DV}{Dt} = \rho g - \nabla p + \mu \nabla^2 V \tag{9}$$

$$dE = dQ + dW \quad (10)$$

To analyze the flow and combustion characteristics of converting from natural gas to hydrogen in a combined cycle gas turbine, computational fluid dynamics software will be used. The software package that will be used for meshing and simulation is the commercial solver Ansys Fluent. The turbulence model used will be the k-omega shear stress transport (SST) model as it handles boundary wall conditions well and is a good balance between accuracy and computation performance [10]. For the combustion model, the non-premixed flamelet model using the GRI-Mech model was used. For blended fuels and for simulations with water injection, a more complex reaction model may need to be considered. For the inlet boundary conditions, flowrates, temperatures, and/or densities of reactants were not obtained from NIPSCO, thus, these conditions were estimated based off the published electrical power output of the system and reversed to the required chemical energy required to produce said power.

Constraints

The largest constraint on the project was not obtaining information from NIPSCO regarding operating conditions, geometry, fuel consumption, etcetera. This drastically constrained research goals as a realistic simulation starts with realistic information and unfortunately there was little data to validate results against. Since data was not obtained about NIPSCO's operating conditions, the results were limited to a theoretical analysis. Furthermore, this limited the scope of findings as the results of the project will not be fully applicable and be accurate enough for NIPSCO to draw conclusions on the efficacy of hydrogen combustion integration. With that said, however, the results give a baseline analysis of feasibility.

In addition to data limitations, another constraint on the analysis was computing power. Computational Fluid Dynamics takes a large amount of computing resources to develop a solution. Since computing resources were limited, the simulations took a long time to process due to the nature of the numerical process and complexity of solution – including the flow equations, equations for reactions, and turbulence. With limited resources, the simulation was designed to be a RANS (Reynolds-Averaged Navier Stokes) simulation. This form of simulation offers the least amount of resolution but offers the fastest compute time. LES, Large eddy simulations, and direct numerical simulations (DNS) are usually reserved for CFD algorithm and computation research applications, albeit offer the highest resolution. In most industrial cases the benefits of this resolution are negligible and RANS simulations are preferred for their computing optimizations.

Standards and Codes

In compliance with Purdue University and Center for Innovation in Visualization and Simulation (CIVS) research standards and requirements, the Collaborative Institutional Training Initiative Program (CITI) training was completed. This training covered plagiarism, conflicts of interest, data management, and research misconduct. In addition to this training the project advisors, Dr. Okosun and Mr. Melvin, have advised us on industry standards and best practices for research and design.

Environmental Impact

The environmental impact of the simulation and research activities were negligible as the only resource used, other than human resources, was computer/electric resources. With that being said, the research herein has a large potential to improve the environment through the reduction of carbon emissions and fossil fuel consumption. Even a small reduction of carbon emissions by the power industry, over time could have significant benefits for the climate. It is hoped that this work is used in the further analysis of cost, benefits, and concerns with the implementation of Hydrogen in gas turbines.

Approach

In the previous semester, a thorough literature review was conducted and most time was spent learning about the computational fluid dynamics software. A baseline case was developed using the Ansys fluent training manual geometry of a can-combustor. From this research a parametric simulation model was developed to simulate a GE 7F series gas turbine, analyzing zero to sixty-five percent hydrogen and its impact on the combustion, emissions, and overall system.

From the ANSYS fluent tutorial, the boundary conditions for the baseline case were determined to be the following:

Table 1: Boundary Conditions from Baseline Model

	Primary air inlet	Fuel inlet	Secondary air inlet	Outlet
Velocity	10 m/s	40 m/s	6 m/s	N/A
Temperature	300K	300K	300K	N/A
Species (mass fraction)	$.23\ O_2$ $.77\ N_2$	$1\ CH_4$	$.23\ O_2$ $.77\ N_2$	N/A
Gage Pressure	N/A	N/A	N/A	0 Pa

With the following boundary conditions, the following CFD and physics models were used:

- Viscous flow (k-omega turbulence model)
- Non-premixed combustion
  - Steady diffusion flamelet model
  - GRI-Mech 3.0 Methane-Air Reaction Mechanism
  - NOx creation enabled (thermal only)
- Volumetric Reaction
- Adiabatic Walls

From the baseline case previously developed, lower heating values of combustion were identified and applied to determine blended hydrogen and methane equivalent fuel mixtures for various percentages of Hydrogen blends from zero to sixty-five percent. To maintain predictable fuel concentrations in the model, the velocity fuel inlet was converted to mass flow rate using the following equation:

$$Volumetric\ Flow = V_{flow} \times area$$

11

Where area was determined to be $1.3932 \times 10^{-5}\ m^2$ from the CAD model. Plugging in the numbers into equation 11 yields:

$$Volumetric\ Flow = 40\frac{m}{s} \times 1.3932 \times 10^{-5}\ m^2$$

12

$$Volumetric\ flow = 0.0033\frac{m^3}{s}$$

13

Once volumetric flow was determined (equation 13), mass flow could be obtained:

$$Mass\ flow = volumetric\ flow \times density$$

14

Where density of methane was found to be $.335\ kg/m^3$ at 300 Kelvin.

$$Mass\ flow =\ .0033\frac{m^3}{s} \times .335\frac{kg}{m^3}$$

15

$$Mass\ flow =\ .00113\frac{kg}{s}$$

16

Once mass flowrate was determined, the thermal energy from combustion could be determined using the heating values of natural gas and an equivalence equation developed:

$$\dot{Q}_{CH_4} = \dot{m}_{CH_4} \times R_{CH_4}$$

17

Plugging in the mass flowrate calculated above and the lower heating value of combustion of methane tabulated above:

$$\dot{Q}_{CH_4} = .00113\,\frac{kg}{s} \times 50\,\frac{MJ}{Kg} = .0563\,\frac{MJ}{Kg}_{CH4}$$

18

With this information, the equitable mass flow rate of pure hydrogen can be determined via the equality:

$$\dot{m}_{CH_4} R_{CH_4} = \dot{m}_{H_2} R_{H_2}$$

19

Solving for hydrogen mass flow rate,

$$\dot{m}_{H_2} = \frac{\dot{m}_{CH_4} R_{CH_4}}{R_{H_2}} = \frac{.0563\,\frac{MJ}{Kg}}{120\,\frac{MJ}{Kg}} = .00047\,\frac{kg}{s}_{H_2}$$

20

From her the general equation was developed to implement various percentages of hydrogen:

$$\dot{m}_{net} = percent_{(H_2)} \times .00047\,\frac{kg}{s} + percent_{(CH_4)} \times .0113\,\frac{kg}{s}$$

21

Where $\dot{m}_{net}$ in equation 21 must equate the following:

$$percent_{(H_2)} + percent_{(CH_4)} = 100\%$$

22

NIPSCO Sugar Creek Generating station operates two GE Power 7F.04 gas turbines where an individual turbine engine was estimated to create 150 Mega Watts of power. In addition, the GE 7F Series turbines are rated to only use up to 65% hydrogen. Using the knowledge that each turbine contains 14 can combustors and the output power already assumes mechanical energy/efficiency loss, the fuel required for such energy output was back calculated and divided by 14 (for energy output per combustor) and was found that the model from the Ansys tutorial needed to be scaled approximately by +6.9%. With this scale, the required mass flow rates were determined as shown in Table 2.

Table 2: Percent Hydrogen and corresponding mass flow rate in kg/s

% Hydrogen	Mass flow rate (Kg/s)	Volumetric Flow (m^3/s)	Volumetric Flow (SCFM)
0%	0.3726608466764003	51.97501348	110585.1
16.25%	0.3559844665541634	50.25919476	106934.5
32.5%	0.33930808643192645	48.48622076	103162.2
48.75%	0.3226317063096894	46.65609147	99268.28
65%	0.3059553261874525	44.7688069	95252.78

Results

In Figure 7, it is observed that by injecting Hydrogen into the fuel stream, the carbon dioxide emissions decrease exponentially, whereas the NOx formation increases linearly as the internal average temperature increases due to hydrogen combustion.

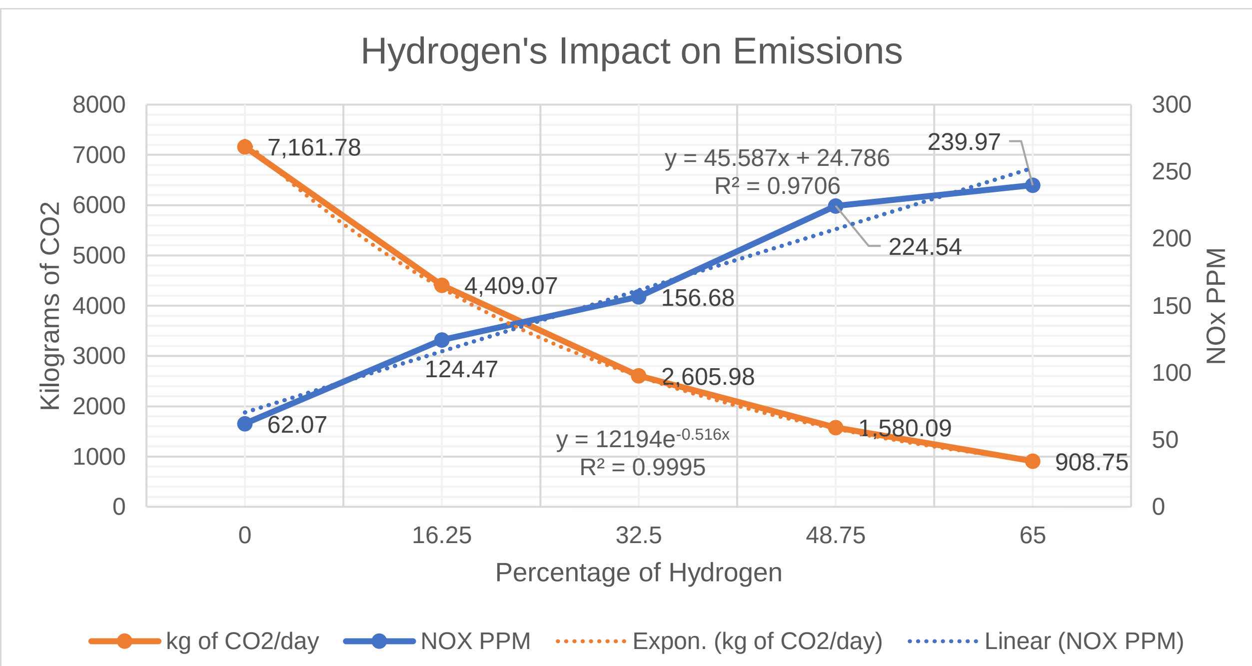


Figure 7: Impact of Hydrogen on Emissions

With the addition of hydrogen, we see a dramatic increase in steam production, albeit hydrogen at any percentage beyond 16.25% does not greatly impact the mass fraction of steam at the outlet. However, the production rate steps 202.14% from baseline on average. If the downstream systems are designed with excess water vapor inconsideration, additional hydrogen should not be a major issue for oxidation of materials.

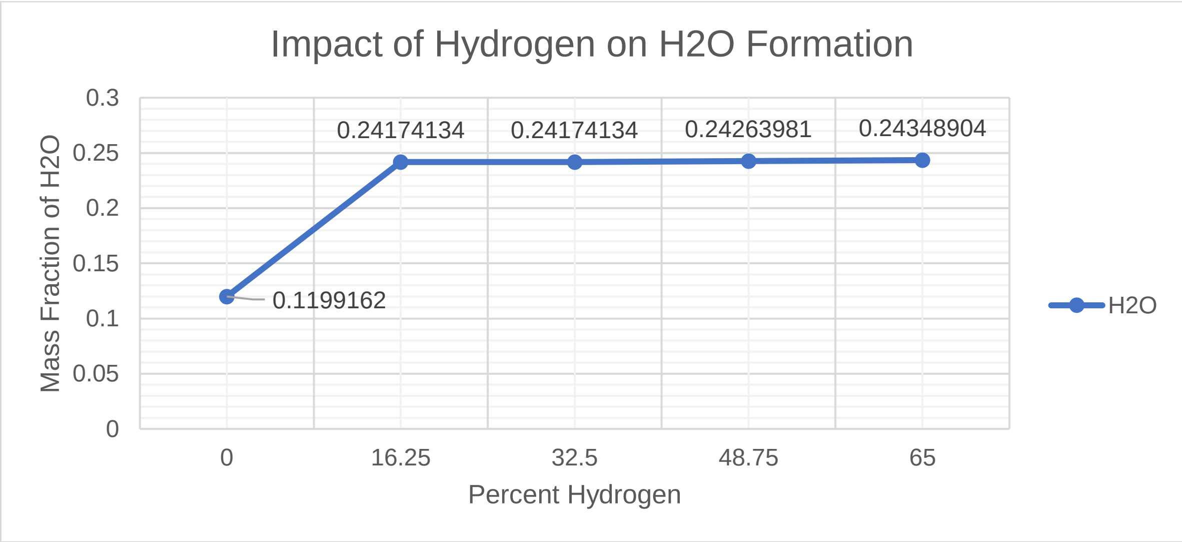


Figure 8: Impact of Hydrogen on H2O Production

In Figure 8, as the Hydrogen percentage increases, the exit velocity increases dramatically (144% of the baseline at 65% Hydrogen), whereas the exit mass flow decreases insignificantly (98% of the baseline mass flow at 65% Hydrogen). This indicates that the momentum at the exit is dependent on the combustion flame speed and thus by extension far greater dependent on the exit velocity over the exit mass flow.

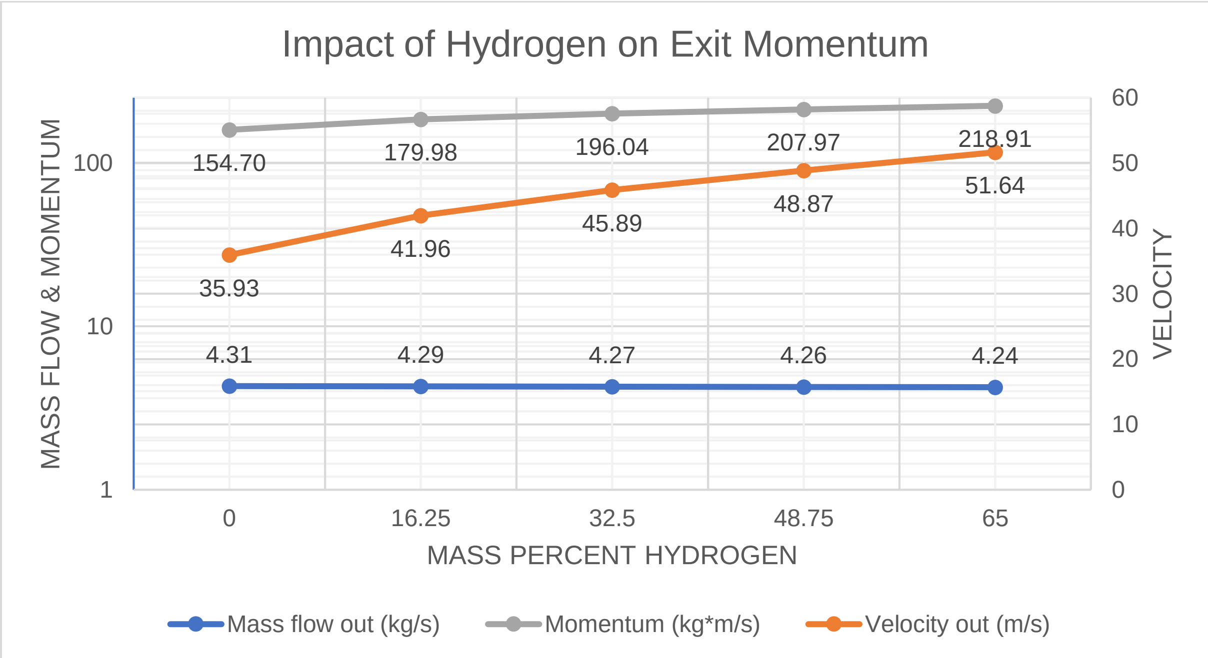


Figure 9: Impact of Hydrogen on Exit Momentum

As predicted the exit temperature as well as the internal temperature increases dramatically with the introduction of Hydrogen gas. This temperature increase is due to the hotter heat of combustion as well as increased efficiency in heat transfer due to brighter combustion and thus greater radiation. From Figure 10 and Figure 11 a 7.7% increase in outlet temperature is and 10.2% internal temperature increase is observed from baseline to extreme case respectively. Note that internal temperature is an average of all gases, including the inlet fuel, thus, is lower than outlet temperature. Both outlet and combustor temperature increase logarithmically.

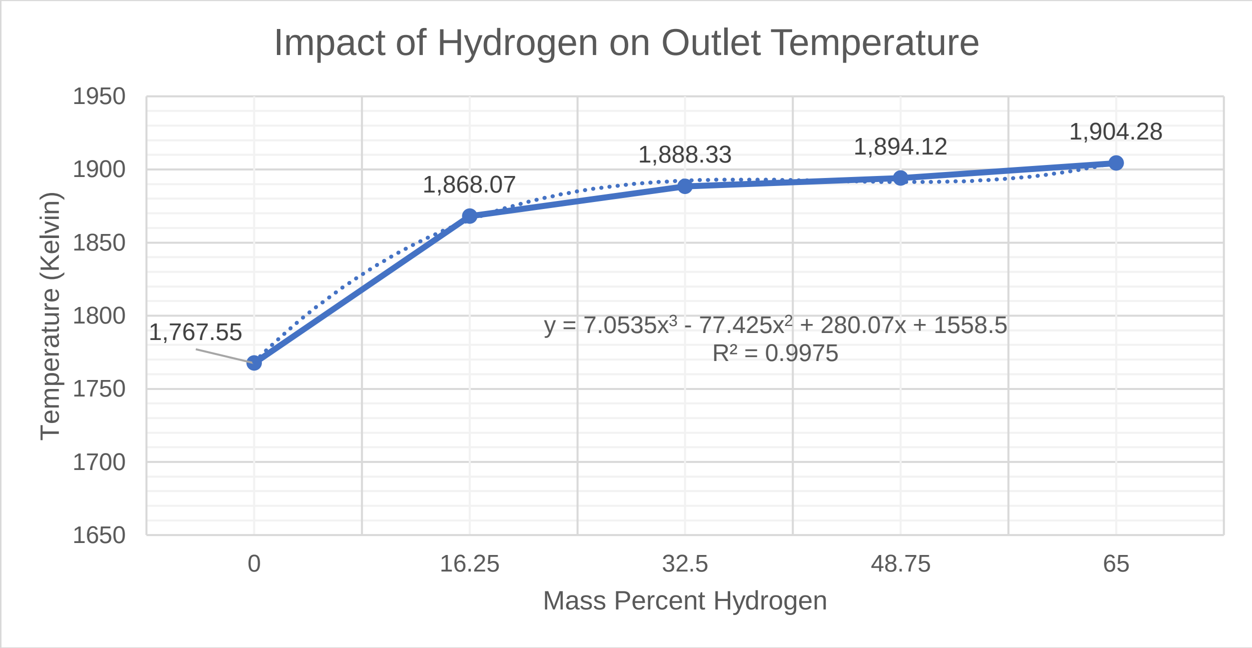


Figure 10: Impact of Hydrogen on Outlet Temperature

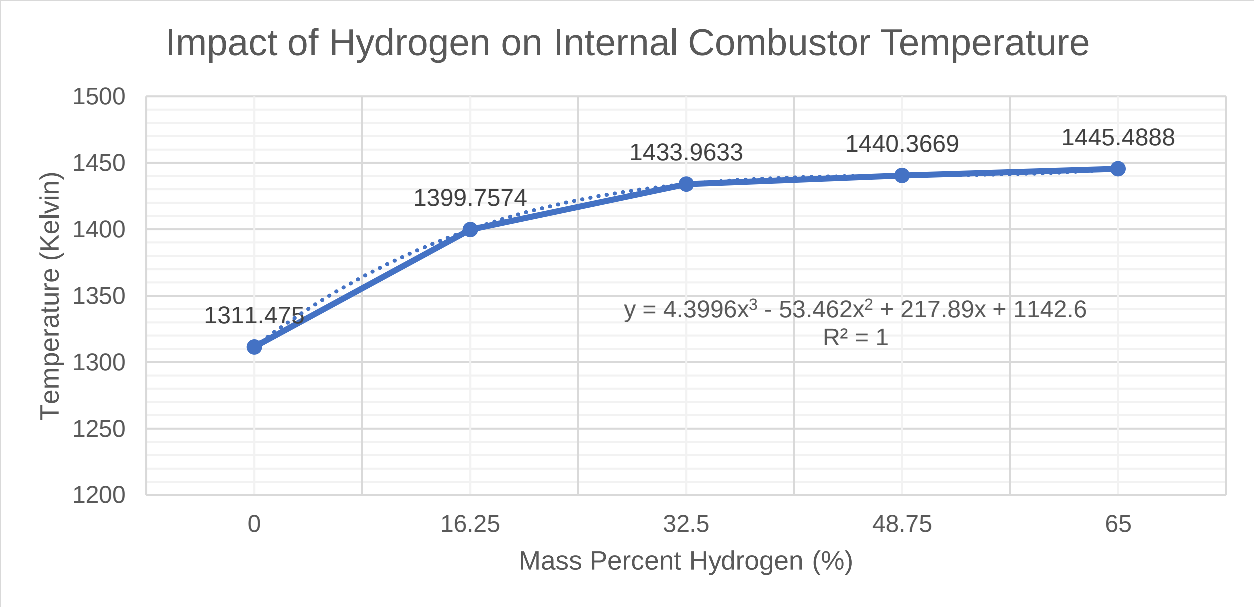
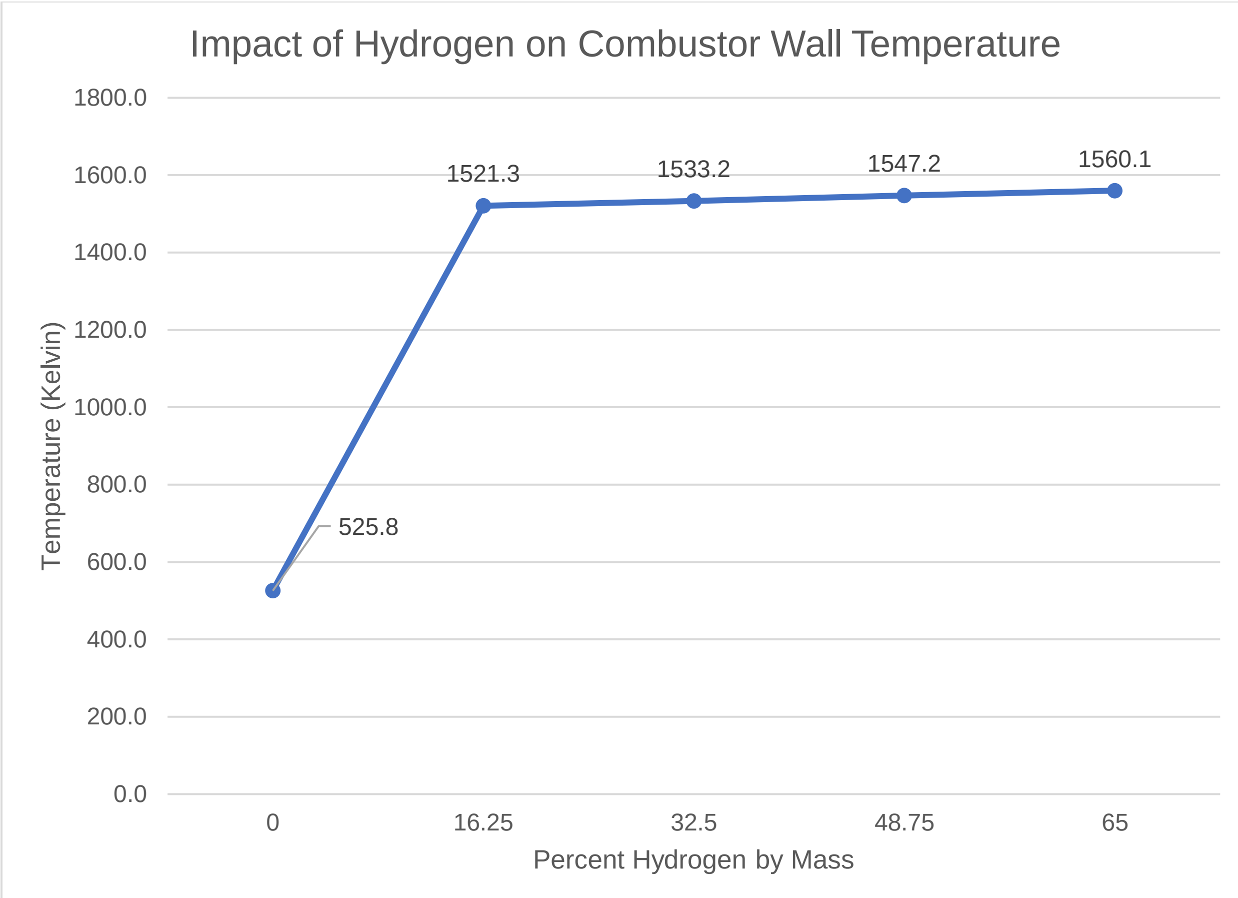


Figure 11: Impact of Hydrogen on Internal Temperature



With the introduction of Hydrogen, the total net fuel consumption also decreased 1.9% from 98.83% for the baseline case to 96.93% for the extreme case as shown in Figure 11. What was unexpected is that the consumption of Methane (solid blue line) increased, however, the hydrogen (solid orange line) consumption greatly decreased as more Hydrogen was introduced in the combustor. This was most likely caused by methane cracking, or the disassociation of carbon and hydrogen in natural gas due to the combustion temperature.

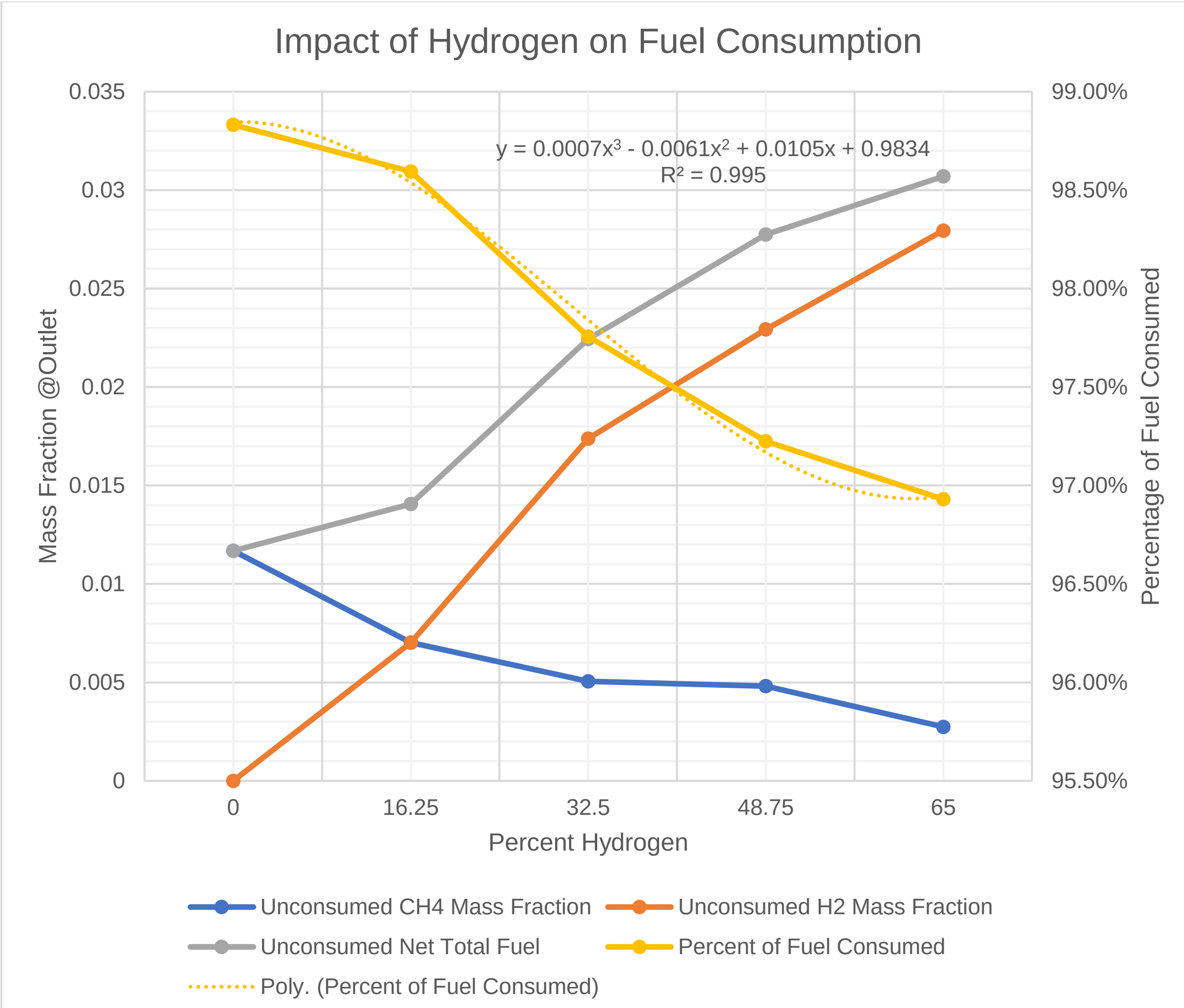


Figure 12: Impact of Hydrogen on Fuel Consumption

The operating costs before tax incentives, renewable energy credits (REC's), and subsidies are estimated in Figure 13. Operating above 16.5% is expected to be infeasible due to exorbitant costs of hydrogen in comparison to natural gas. However, with renewable energy incentives and the potential of a carbon emission tax, implementing Hydrogen blended fuels could become significantly more cost competitive. In addition, various sources of hydrogen and their respective costs are shown. As of this report, the costs are as follows: \$12.00/kg for green hydrogen, \$4.00/kg for gray hydrogen, \$2.50/kg for brown, \$8.00/kg for gray with carbon capture and sequestration, and \$6.50 for brown with carbon capture and sequestration. Where green Hydrogen is from renewable electrolysis, gray is from methane cracking, and brown hydrogen is from coal/syngas respectively.

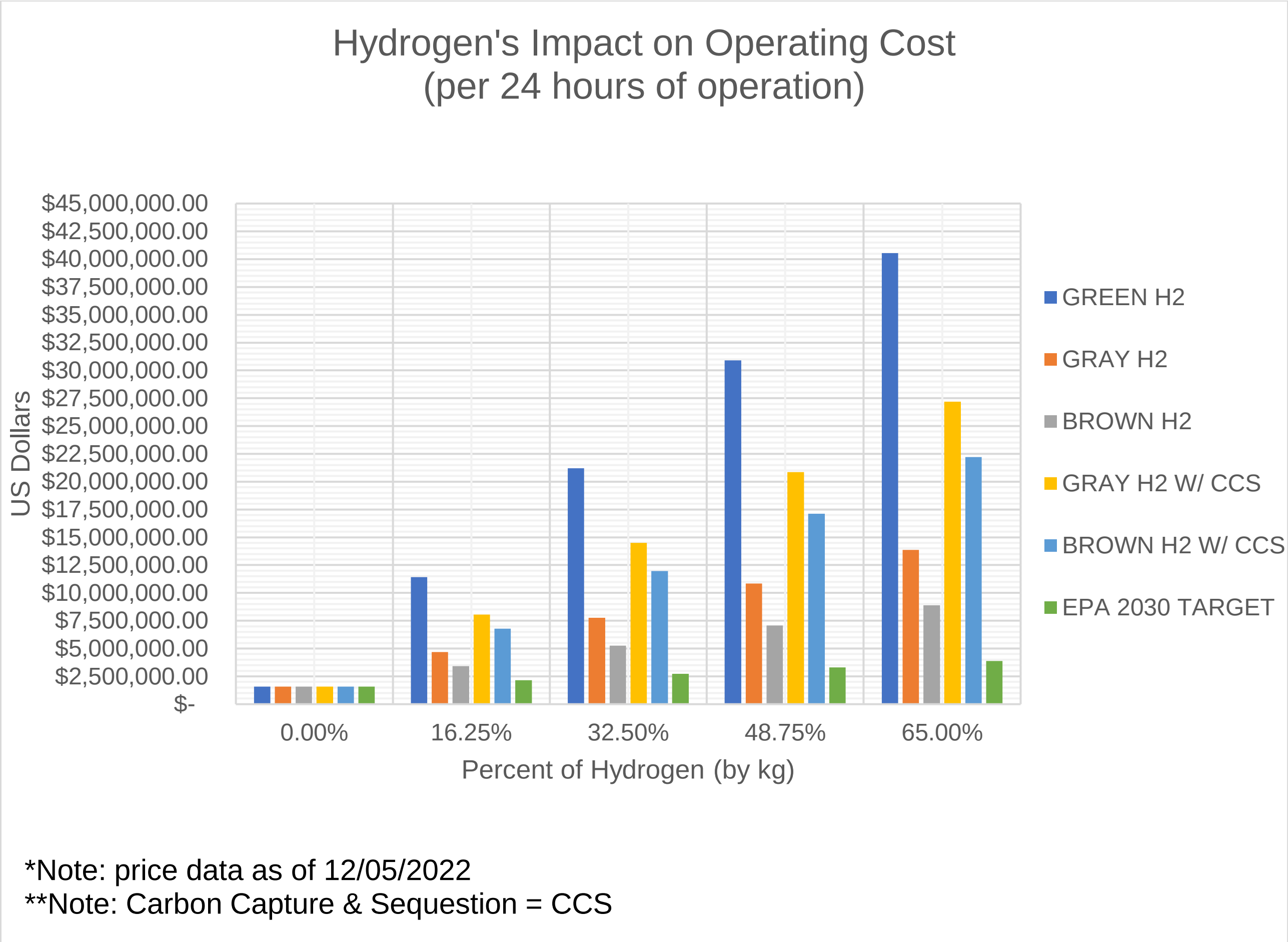


Figure 13: Impact of Hydrogen on cost

Discussion

From the results, it is observed that the increased thermal nitrogen oxide production rate is linear, whereas the reduction of carbon dioxide follows an exponential trend. This signifies that hydrogen as a fuel additive is exceptional at the reduction of carbon emissions, even if a significantly smaller mixture rate is economically chosen than the simulated cases herein. In the case of mitigating thermal NOx production, further experimentation could be performed on water injection to reduce peak flame temperature, throttling down the engine, and implementing a selective catalytic reduction (SCR) system. As NOx emissions are almost 400% more than baseline for the 65% by mass hydrogen case, NOx emissions and mitigation are singlehandedly the largest concern with implementing hydrogen blended fuel into gas turbine engines.

In addition to NOx emission concerns, the steam production rate is double the baseline case. This is not unexpected however, as since we are injecting 50% more H_2 into the reaction, there is excess hydrogen available to bond with oxygen to produce water. If downstream components are designed for excess humidity and oxidation, excess water production should not be of major concern. It is observed however, that no matter what percent hydrogen introduced, it does not greatly impact the steam production rate and the increase in steam production is nearly constant.

Although hydrogen is a far less dense substance than its natural gas counterpart, this had little effect on the net outlet mass flow rate. The momentum chart (Figure 9) shows an increase in outlet momentum which is directly correlated to an increase in outlet velocity rather than exit mass flow. This was unexpected, though it demonstrates great potential to throttle down the engines and still meet or exceed current performance.

Another insight is that the outlet temperature and internal temperature increases 1,765K to 1904K and 1311K to 1445K respectively. From a materials standpoint, Hastelloy X, a common alloy used in combustion systems is resistant to oxidation up to 1477K. Therefore, in this simulation, the combustor is operating well above recommended temperatures and therefore temperature control is not only necessary for NOx emission mitigation but also for system integrity. The true temperature of such a combustor would most likely be less than simulated, however, as walls were assumed to be adiabatic. Natural conduction and convection on the outer walls should cool down the combustor some, and from Figure 37, it is observed that peak temperatures occur in the center of the combustor and is cooler along the walls. If hot gases are not in contact with the walls of the combustor, internal process temperatures can be hotter than recommended material integrity operating temperatures as is typically the case in the design of the turbine stage blades.

An unexpected trend was the impact of hydrogen had on the fuel consumption. With the introduction of Hydrogen, fuel consumption decreased from greater than 98.5% to less than 97%. In addition, natural gas consumption increased dramatically whereas hydrogen consumption decreased greatly. It is my intuition that as natural gas combustion mechanism is slower and more complicated process, the injected hydrogen combusts quickly in comparison to methane, which depletes some of the oxidizer available. After natural gas is broken down into its free radicals, there is less oxygen to react and therefore the hydrogen supplied from the natural gas molecules do not have time to react before exiting the combustor. This is known as methane cracking. Additional experimentation could be performed on throttling and altering the equivalence ratio to increase complete combustion.

During research and development of this parametric simulation, it was difficult to obtain real operating conditions, geometry, and other data regarding the General Electric combustors due to export and International Traffic in Arms Regulations (ITAR). Many assumptions were made, and considerations of efficiency and output power loss were ignored or otherwise assumed to be included in the published documentation that was found regarding the system performance.

Conclusion

From the research and simulations performed, implementing hydrogen in a combined cycle gas turbine generator designed to combust natural gas is not only feasible, but it also brings many benefits including increased performance and a significant reduction of carbon dioxide emissions. If further cost analysis is to be performed, it would be of interest of NIPSCO or any organization operating CCGT's to investigate the fuel savings of throttling engines. In addition to throttling, it would be advantageous to also investigate government grants, subsidies, and tax abatements on implementing hydrogen combustion as even in the case of less than 16.5% hydrogen, the simulations show that a performance increase would be observed, and carbon dioxide emissions would be reduced greatly. With these benefits, even though hydrogen fuel is far more expensive than natural gas, there may exist a cost-optimized point where burning a percentage of hydrogen fuel reduces the cost of operation over the cost of operating 100% natural gas. If the EPA hits the target of $1.00/kg for Hydrogen fuel, then the operating cost is marginally greater for Hydrogen blended operation versus the baseline methane combustion.

To address NOx emission issues, the lowest cost option is water injection into the combustion chamber and has been shown to reduce NOx emissions in Diesel engines by 85%. However, to meet ever increasing emission requirements, an aftertreatment or selective catalytic reduction system may also need to be fitted onto the system. The impact of thermal NOx and combustion Temperature are dependent on one another and if NOx production is addressed then thermal operating concerns too would be mitigated.

Other concerns that were not studied in this study include flame stability, flame length, and radiative heat transfer of hydrogen. With a rising flame speed and a decrease in flame length (due to hydrogen), combustion stability can greatly be reduced causing downtime or issues with out of family operating conditions. If radiation was considered, there may even be a higher performance increase than what was observed in our simulation. It is hoped that the research presented here demonstrates opportunities in electric generation systems to incorporate green technologies and addresses the various concerns in implementing hydrogen into a gas turbine.

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APPENDIX A – COMPUTATIONAL FLUID DYNAMIC CONTOURS

Baseline Case (100% Methane)

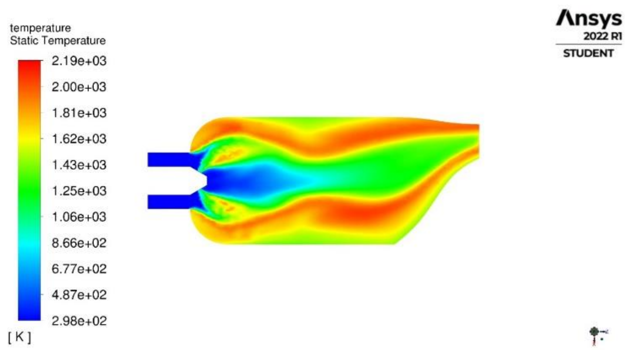


Figure 14: 100% Methane Static Temperature

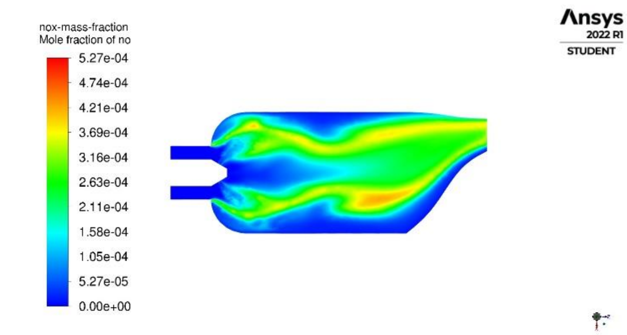


Figure 16: 100% Methane NOx Mass Fraction

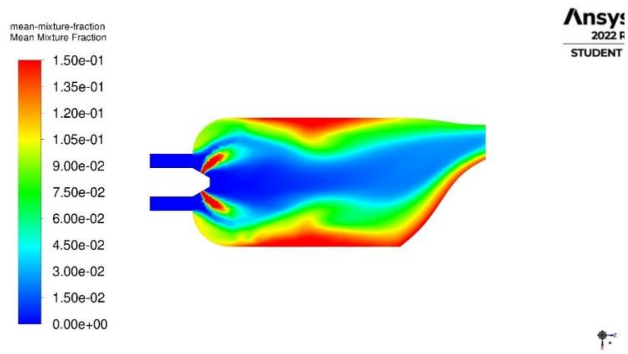


Figure 15: 100% Methane Mean Mixture Fraction

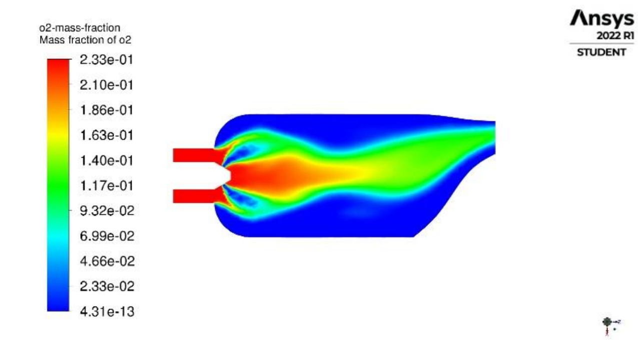
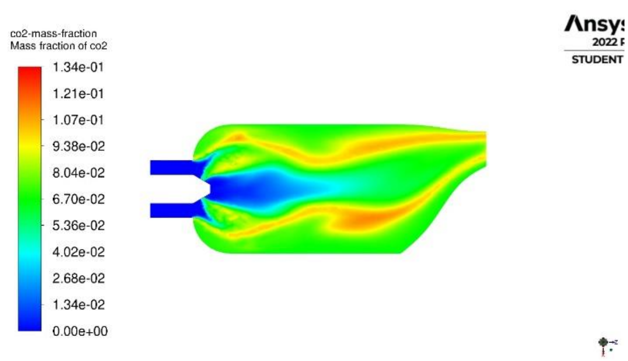


Figure 17: 100% Methane O2 Mass Fraction



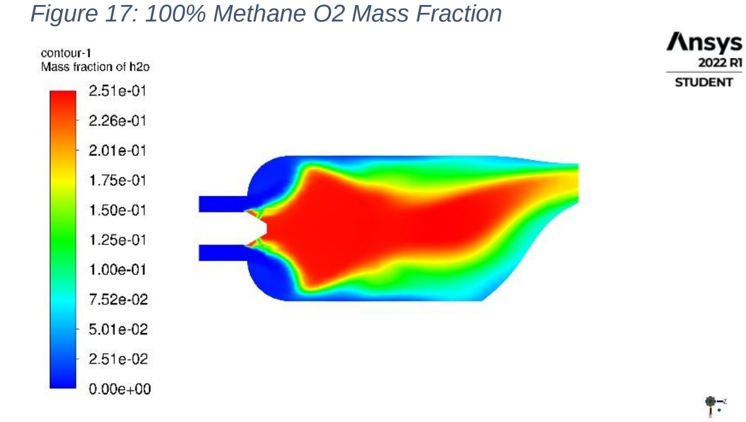


Figure 18: 100% Methane H2O Mass Fraction

Figure 19: 100% Methane CO2 Mass Fraction

Results for 16.25% Hydrogen

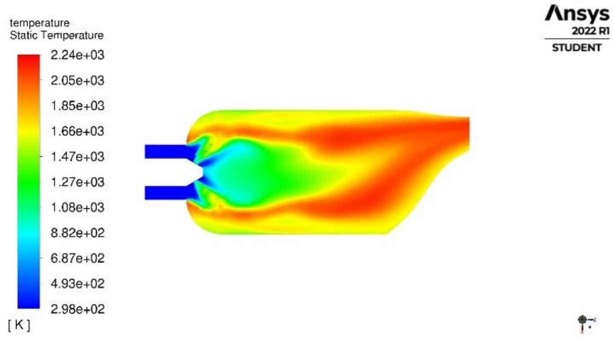


Figure 20: 16.25% Hydrogen Static Temperature

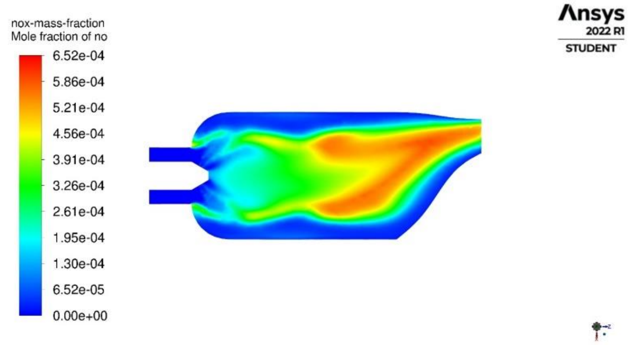


Figure 23: 16.25% Hydrogen NOx Mass Fraction

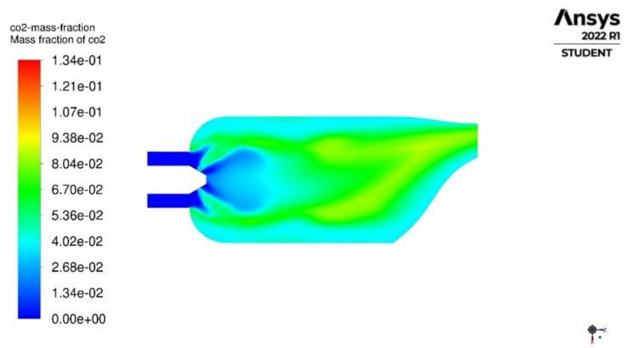


Figure 21: 16.25% Hydrogen CO2 Mass Fraction

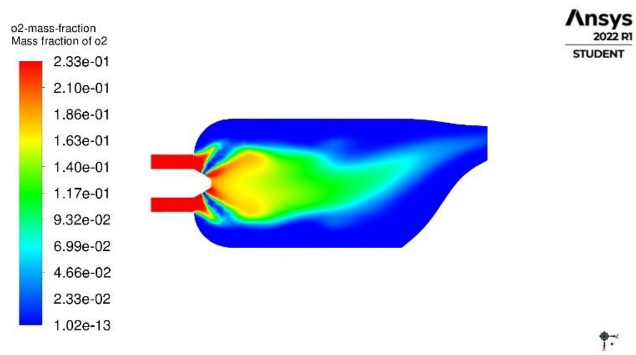


Figure 24: 16.25% Hydrogen O2 Mass Fraction

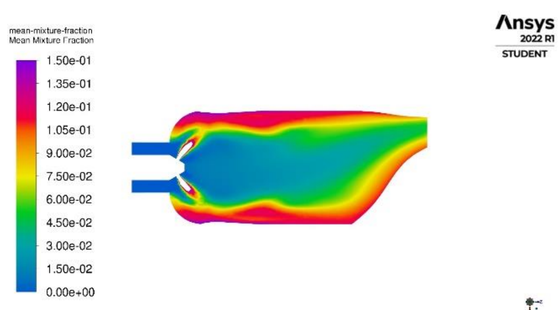


Figure 22: 16.25% Hydrogen Mean Mixture Fraction

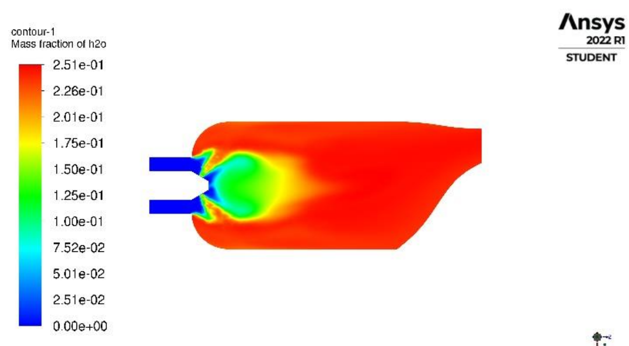


Figure 25: 16.25% Hydrogen H2O Mass Fraction

Results for 32.5% Hydrogen

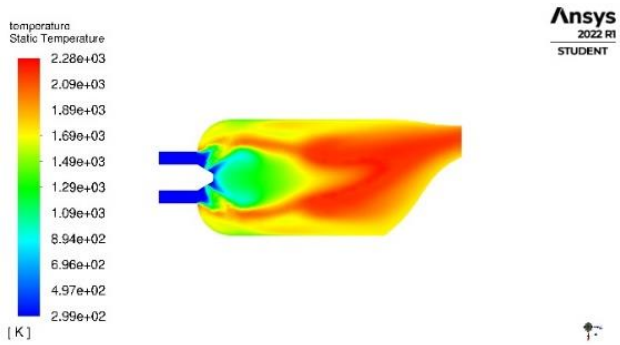


Figure 26: 32.5% Hydrogen Static Temperature

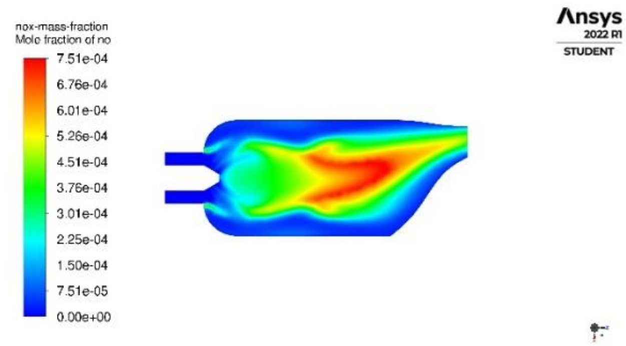


Figure 29: 32.5% Hydrogen NOx Mass Fraction

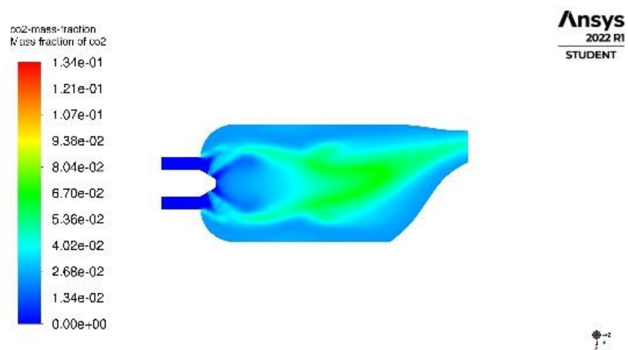


Figure 27: 32.5% Hydrogen CO2 Mass Fraction

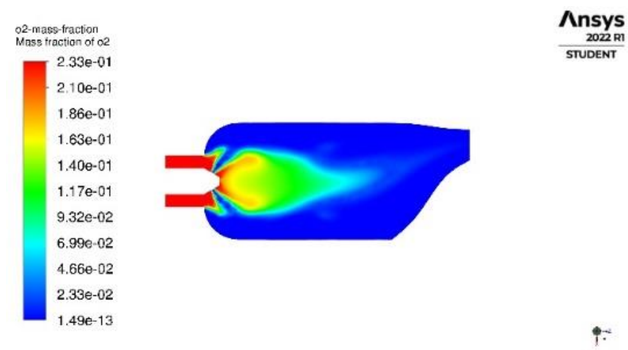


Figure 30: 32.5% Hydrogen O2 Mass Fraction

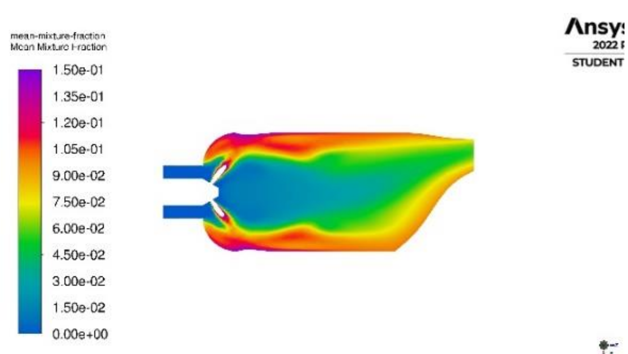


Figure 28: 32.5% Hydrogen Mean Mixture Fraction

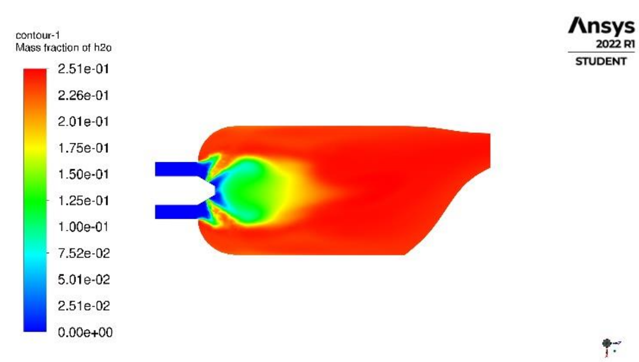


Figure 31: 32.5% Hydrogen H2O Mass Fraction

Results for 48.75% Hydrogen

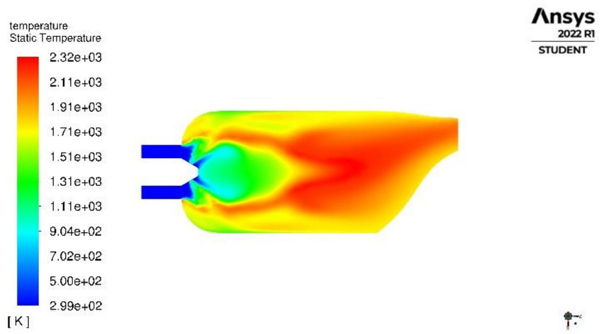


Figure 32: 48.75% Hydrogen Static Temperature

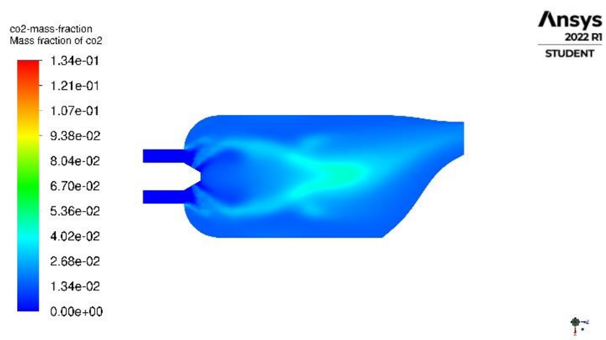


Figure 33: 48.75 Hydrogen CO2 Mass Fraction

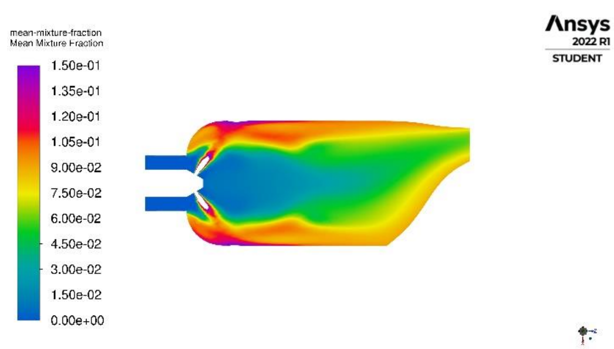


Figure 34: 48.75% Hydrogen Mean Mixture Fraction

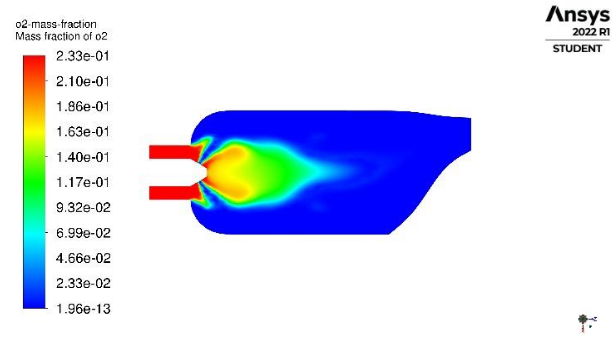


Figure 35: 48.75% Hydrogen O2 Mass Fraction

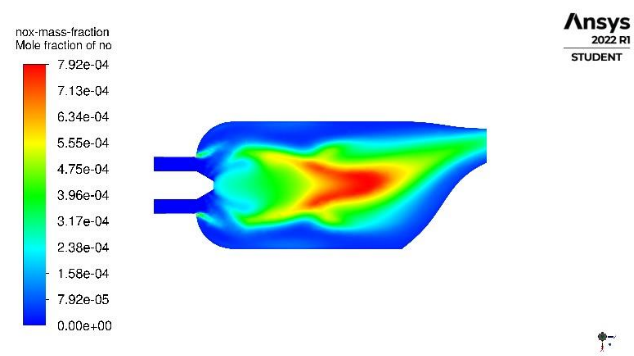


Figure 36: 48.75% Hydrogen NOx Mass Fraction

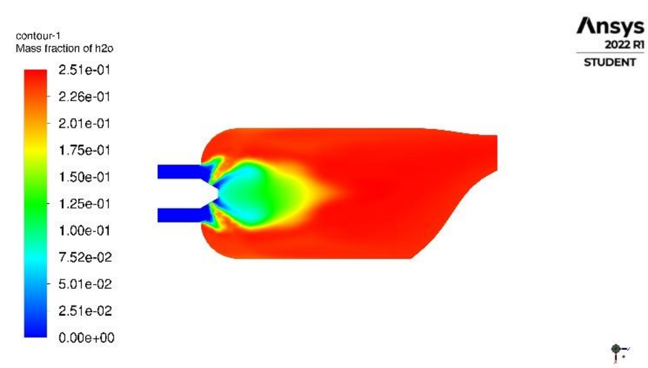


Figure 37: 48.75% Hydrogen H2O Mass Fraction

Results for 65% Hydrogen

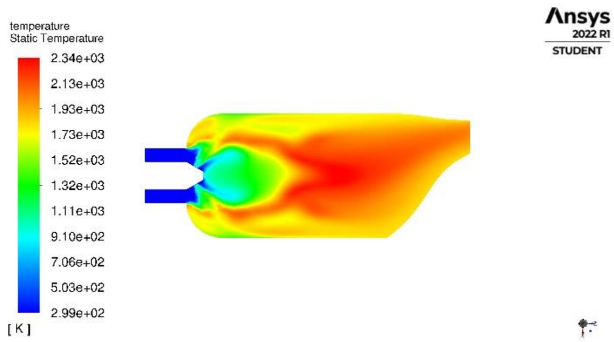


Figure 38: 65% Hydrogen Static Temperature

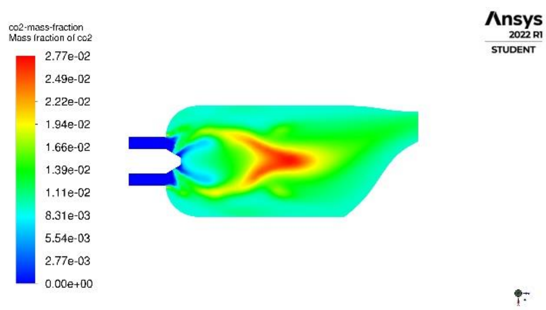


Figure 39: 65% Hydrogen CO2 Mass Fraction

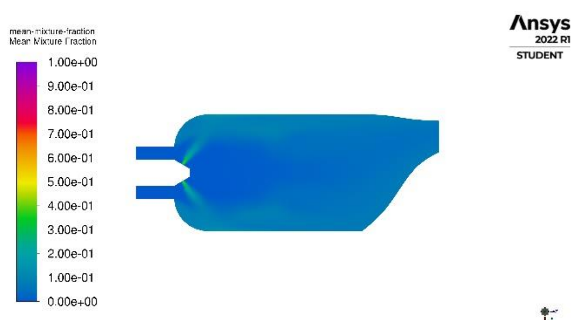


Figure 40: 65% Hydrogen Mean Mixture Fraction

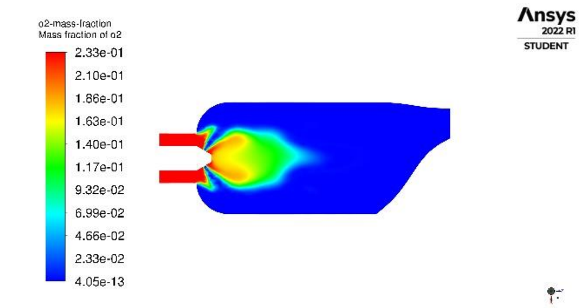


Figure 41: 65% Hydrogen O2 Mass Fraction

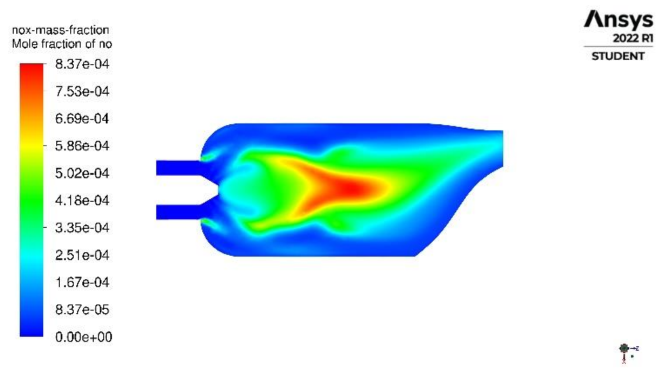


Figure 42: 65% Hydrogen NOx Mass Fraction

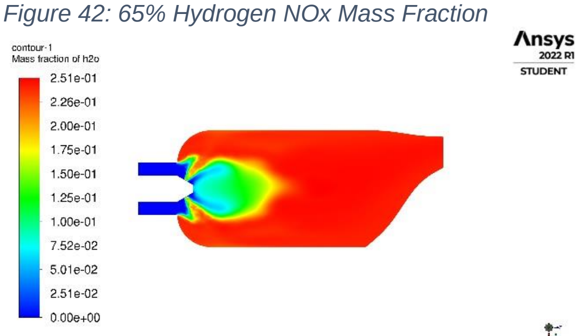


Figure 43: 65% Hydrogen H2O Mass Fraction

APPENDIX B – PYTHON CODE

```
def volumetric_flow(area, velocity):
    return area * velocity

def mass_flow(area, velocity, density):
    VF = volumetric_flow(area, velocity)
    return VF * density

def heat_flux(mass_flow, heat_val):
    return mass_flow * heat_val

def equivalence(mdot_1, R_1, R_2):
    return (mdot_1 * R_1 / R_2)

def mass_fraction(H2, CH4, percentage):
    mass_fractions = []
    for i in percentage:
        mass_fraction_h2 = H2 * (i / 100)
        mass_fraction_ch4 = CH4 * ((100 - i) / 100)
        total = mass_fraction_h2 + mass_fraction_ch4
        mass_fraction_list = [mass_fraction_h2, mass_fraction_ch4, total]
        mass_fractions.append(mass_fraction_list)
    return mass_fractions

def energy_fuel_required(output, fuel_heat_generation):
    return output * (1 / 3412.14) * fuel_heat_generation




if __name__ == '__main__':

    surface_area = 1.3932 * 10 ** (-5) # m^2
    number_of_ports = 6
    total_surface_area = surface_area * number_of_ports

    velocity = 40 # m/s
    density = 0.337 # kg/m^3

    OUTPUT = 5934 #BTU
    FUEL_HEAT_GEN = 50 #MJ/kg -CH4

    MCH4 = 0.3726608466764003
    RCH4 = energy_fuel_required(OUTPUT, FUEL_HEAT_GEN)
    print(RCH4)
    RH2 = 120

    percentage = [0, 16.25, 32.5, 48.75, 65]

    #CH4_heat_flux = heat_flux(MCH4, RCH4)
    #print(CH4_heat_flux)

    MH2 = equivalence(MCH4, RCH4, RH2)
    print('The Mass flow rate of H2 @ 100%: {}'.format(MH2))
    print('THe Mass flow rate of CH4 @ 100%: {}'.format(MCH4))
    print(' ')
    mfs = mass_fraction(MH2, MCH4, percentage)
    index = 0
    for each in mfs:
        print('Total Mass Flow Rate {} for {}% hydrogen'.format(each[2], percentage[index]))
        index += 1

    H2_1 = 0.0011268201600000002
    H2_2 = 0.0009624922200000002

    #PERCENT = (H2_2 - H2_1 / H2_1) * 100
    #print('Percent difference from actual to theoretical {}'.format(PERCENT))
```